Decision 05-10-014 October 6, 2005

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement the California Renewables Portfolio Standard Program.	Rulemaking 04-04-026 (Filed April 22, 2004)

INTERIM OPINION APPROVING LONG-TERM RENEWABLES PORTFOLIO STANDARD PLANS

I. Summary

We conditionally approve the long-term procurement plans for the Renewables Portfolio Standard (RPS) program submitted by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), and require the utilities to supplement their plans with further information on transmission planning and contingency planning. We also direct that, in the future, long-term RPS planning be undertaken in our general procurement planning proceeding, Rulemaking (R.) 04-04-003 or its successor proceedings.

II. Procedural History

This proceeding was opened in April 2004 to continue our implementation of the RPS program created by Senate Bill 1078, effective January 1, 2003. Decision (D.) 03-06-071, the first of our decisions setting parameters and requirements for the RPS program, was issued in R.01-10-024.

The Assigned Commissioner's Ruling and Scoping Memo Establishing Schedule for Phase Two of the Renewables Portfolio Standard Proceeding (Scoping Memo) (December 16, 2004) set a schedule for addressing a range of issues, including long-term planning and the utilities' 2005 RPS solicitations. In D.04-12-048, issued in R.04-04-003, we found that the utilities' long-term procurement plans did not adequately address their 2010 renewable procurement goals. We instructed them to submit revised long-term RPS plans in this proceeding. In accordance with the Scoping Memo, the utilities filed long-term plans and 2005 plans and draft requests for offers (RFOs) together. PG&E and SCE filed their short- and long-term RPS procurement plans, with redacted public versions and confidential versions filed with requests that they be kept under seal, on March 7, 2005. SDG&E filed its short and long-term RPS procurement plan, with redacted public version and confidential version filed with a request that it be kept under seal, on April 15, 2005. Comments on the PG&E and SCE plans were filed April 7 and April 21, 2005; comments on the SDG&E plan and reply comments on the PG&E and SCE plans were filed on May 6, 2005. Reply comments on SDG&E's plan were filed May 13, 2005.[1] In D.05-07-039, we approved with modifications the utilities' 2005 short-term procurement plans and RFOs.

This decision addresses the long-term plans, which we delayed in D.05-07-039 because certain information from SCE relevant to our discussion of

[1] Comments and/or reply comments were filed by California Wind Energy Association (CalWEA); Center for Biological Diversity; Center for Energy Efficiency and Renewable Technologies (CEERT) Green Power Institute (Green Power); Independent Energy Producers Association (IEP); Office of Ratepayer Advocates (ORA); The Utility Reform Network (TURN); Union of Concerned Scientists (UCS); PG&E; SCE; and SDG&E.

the long-term plans was made publicly available too late to be included. The relevant information having been provided, we now turn to a review of long-term RPS planning.

III. Discussion

A. Overview of Long-Term Plans

1. PG&E

In its long-term plan, PG&E proposes to meet its 2010 goal by acquiring about 900-1000 gigawatt-hours per year (GWh/yr) of new renewable energy, a rate that is about 1-¼ per cent of its projected annual retail sales. PG&E states a strong preference for renewable resources in its service territory, providing a "resource stack" that ranks its current resource planning preferences:

a. Renewable dispatchable resources in NP-15;
b. Renewable firm baseload resources in NP-15;
c. Repowered wind in NP-15;
d. Solar in NP-15;
e. Solar outside of NP-15;
f. New wind in NP-15;
g. Firm baseload resources outside of NP-15; and
h. New wind outside of NP-15.

PG&E applies these planning preferences in its illustrative plan for its renewable resource acquisitions, which we show in a tabular form below.

PG&E 2010 Illustrative Projections

Resource	MW	Approx. % of RPS
New wind*	450	28
Repowered wind*	400	24
Geothermal	400	24
Biomass	150	9
Biodiesel	50	3
Solar	200	12
TOTAL	1650	100

PG&E 2014 Illustrative Projections

Resource	MW	Approx. % of RPS
New wind*	550	28
Repowered wind*	400	20
Geothermal	450	23
Biomass	150	8
Biodiesel	150	8
Solar	250	13
TOTAL	1950	100

*In PG&E's service territory

PG&E intends to use all procurement options, including RPS solicitations, general procurement, bilateral negotiations, and possible utility ownership, to obtain the projected quantity of renewable energy. PG&E reports that its initial conceptual analysis of transmission upgrades needed in its service territory to achieve the 2010 goal showed costs of upgrades between $170 and $230 million, but does not provide any information about the location, scope, or timing of any of the possible upgrades. PG&E, relying on the Energy Commission's Renewable Resource Development Report (Nov. 24, 2003),[2] does not anticipate requiring resources from outside its service territory, and does not address any out-of-territory transmission issues.

2. SCE

SCE provides a "base case," "high need case," and "low need case" in its analysis.[3] Although it has not developed a formal resource "stack," SCE indicates that its current view of resources that best meet its operational need is: (1) peaking resources, such as solar; (2) baseload resources, such as geothermal and biomass; and (3) intermittent resources, such as wind. SCE notes that its planning is roughly based on the current mix of renewable resources delivered under Qualifying Facility (QF) contracts pursuant to the federal Public Utility Regulatory Policies Act of 1978 (PURPA). In terms of capacity, this mix is about 42% wind, 31% geothermal, 15% solar, 10% biomass and 2% small hydro.[4] SCE adds that it intends to contract with a large solar project that will begin deliveries in phases, beginning with 2010. By 2010, SCE intends to procure approximately 403 MW, shown in tabular form below.

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[2] This report is available at http://www.energy.ca.gov/reports/2003-11-24_500-03-080F.PDF.

[3] These alternatives are a useful planning tool, especially when accompanied by analysis like that SCE provides. Because PG&E and SDG&E did not provide a similar analysis, we confine our discussion here to SCE's base case.

[4] SCE estimates that this mix translates to deliveries of energy of about 22 % wind, 59% geothermal, 11% biomass, 7% solar and less than 1% small hydro.

SCE 2010 Illustrative Projections

Resource	MW	Approx. % of RPS
Wind	1680	42
Geothermal	68	17
Biofuels	37	9
Small hydro	5	1
Solar thermal	1250	31
TOTAL	403	100

SCE 2014 Illustrative Projections (with solar)

Resource	MW	Approx. % of RPS
Wind	297	30
Geothermal	120	12
Biofuels	63	6
Small hydro	10	1
Solar thermal	500	51
TOTAL	890	100

In its planning without the large solar project, SCE eliminates the "solar" category, leading to a 2014 mix of about 68% wind, about 15% for each of geothermal and biomass, and less than 2% small hydro.[5]

SCE identifies a number of transmission upgrades and new projects that could accommodate additional geothermal and wind generation, as well as some

5 SCE separately estimates energy procurement from repowers and expansions of existing wind projects.

solar generation. SCE projects these upgrades coming into service between 2007 and 2014.[6] These transmission projections are not linked to specific renewable projects, but rather to estimates of future RPS procurement from the various resource areas SCE identifies.

3. SDG&E

SDG&E reaffirms its commitment to reach the 20% goal by 2010, and estimates that eligible renewable resources constituting about 5.7% of its baseline retail energy supply are now under contract for 2010, leaving about 2,500 GWh to be procured. SDG&E continues its use of a resource stack to show its preferences for types of procurement, but notes that the stack is illustrative. Its current resource preferences are:

a. Biomass or biogas in its service area;
b. Wind in its service area;
c. Solar in its service area;
d. Solar outside its service area;
e. Geothermal outside its service area;
f. Biomass or biogas outside its service area; and
g. Wind outside its service area.

SDG&E's projections for 2010 are presented in tabular form below. About a quarter of this total is estimated to be from within its service territory.

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[6] SCE has filed applications for the projects for the renewables labeled "Tehachapi area wind," in its Table 9, Application (A.) 04-12-007 and A.04-12-008.

SDG&E 2010 Illustrative Projections

Resource	MW	Approx. % of RPS
Wind	312	40
Geothermal	190	24
Biogas	45	6
Biomass	40	5
Small hydro	11	1
Solar	182	24
TOTAL	780	100

SDG&E adopts a target of 24% renewables by 2014, continuing incremental growth of 1% per year past 2010. It currently has about 4.6% of that total under contract. Its projections for 2014 are given in tabular form below. The proportion of resources from its service territory remains at about 25%.

SDG&E 2014 Illustrative Projections

Resource	MW	Approx. % of RPS
Wind	484	45
Geothermal	210	20
Biogas	45	4
Biomass	40	4
Small hydro	11	1
Solar	285	26
TOTAL	1075	100

SDG&E also states that, unless a major transmission upgrade is in place and a market mechanism for trading renewable energy credits (RECs) is available, it will not in fact attain the RPS target in 2010. Its plan therefore assumes that significant new transmission will be built, in the form of at least a new 500 kV transmission line. The plan does not include any proposals for new transmission, nor does it identify the issues that would require discussion in an application for a certificate of public convenience and necessity (CPCN) for any new transmission.

B. Common issues

1. Planning

In the Scoping Memo[7], the utilities were directed to prepare

> . . . an RPS plan that accomplished three things: attainment of RPS goals for 2005. . .; a detailed plan for RPS procurement over the period 2005-2014, with an emphasis on achieving the 20% RPS goal in 2010 and including necessary transmission expansion; and a plan for attaining the optimum amount of generation from re-powered renewable facilities presently under contract to the utility. All three components of the plan should incorporate lessons learned during the 2004 RFP solicitations.

The Scoping Memo makes clear that the point of the long-term planning exercise is to prepare a map that will get the utilities to the 20% goal in 2010. To be effective, such a map should not simply express the utilities' preferences, other things being equal. It should also identify and analyze potential problems and delays and develop alternate routes to respond to identified problems.

Each element of the plan should be directed to analyzing, identifying, and implementing steps to reach the 2010 goal and maintain or expand it in future years.[8] To the extent that the plans submitted do not adequately focus on

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[7] These directions implement Pub. Util. Code § 399.14(a)(3). All future references to sections refer to the Public Utilities Code.

[8] See § 399.15. See also Energy Action Plan II: Implementation Roadmap for Energy Policies. (Available at http://www.cpuc.ca.gov/PUBLISHED/REPORT/49078.htm.)

particular elements that are necessary to planning for compliance, we will direct the utilities to supplement their plans.[9]

Both PG&E and SDG&E present resource "stacks" as part of their plans; SCE identifies operational preferences. As we observed in D.05-07-039, these "stacks" and preferences can only be illustrative, and cannot substitute for the least cost/best fit analysis of actual bids in RPS solicitations. In long-term planning, even more than annual procurement, however, it is difficult to strike a balance between the utilities' reasonable planning assumptions and initial preferences and the rigorous application of least cost/best fit analysis to specific project proposals for RPS procurement. Without making some initial assumptions, the utilities are not planning. If the assumptions are too rigid or too limited, the planning process is not robust enough to be useful and may impinge on the least cost/best fit evaluation process. The plans need to be more than bald statements of preference; if they prioritize resources, they must provide analysis that justifies the preference *in terms of meeting the utility's RPS targets.* At the least, the utilities must make explicit the basis of the initial planning assumptions about resources, whether ordered stack or, in SCE's case, projection of current renewables mix. In addition, all utilities should include high, low, and base cases, with supporting analysis, as SCE did in its current plan.

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[9] These supplements will be compliance filings, which do not require comment from the parties. We expect the utilities to structure their supplements to maximize the information and analysis in the public versions of the supplements and to minimize the amount of information for which they request confidential treatment. Our usual rules and practices on confidentiality will apply to the supplements.

In their future long-term plan filings (but not in the supplements ordered today), the utilities must also include a discussion of "lessons learned" from all prior planning cycles. We would expect this discussion to include, at a minimum, analysis of whether the utilities' assumptions were borne out in practice, changes to the utilities' situation that require major revisions to assumptions, and other necessary adjustments as time goes on.

Assumptions about the mix of resources also impact other critical planning elements, such as transmission planning. If the utility's planning assumptions suggest minimal need for investment in transmission, but those assumptions are not justified, a necessary planning step (transmission improvements) will be missed. If the assumptions suggest too much need for transmission, steps that the utility could take to facilitate easier or less expensive methods of RPS procurement may be overlooked.

2. Transmission Planning

The Scoping Memo emphasized that analysis of transmission needs is a required part of the utilities' long-term RPS planning process. This is only common sense, since theoretically available renewable resources will become delivered electricity only if the electricity can be delivered. PG&E and SDG&E did not meet this requirement, as we discuss more fully below. SCE did include transmission planning, but should bolster its analysis.

This issue is not merely theoretical. Wind, new or repowered, geothermal resources, and (for SCE), a large solar thermal project play a major part in the utilities' illustrative plans. For the most part, these resources are in areas remote from the utilities' load centers. This makes analysis of transmission issues and transmission planning not optional, but imperative. The plans are disappointing in this regard, even though the Scoping Memo required transmission planning to be discussed. Since transmission planning and construction take a long time and involve the potential for significant delays, scenarios including all projected transmission additions and upgrades, less than all projected transmission upgrades, and no transmission additions and upgrades should be expressly considered in the long-term plans.

Efforts begun in Investigation (I.) 00-11-011 to examine systematically the issues of transmission of renewable energy from remote resource areas demonstrate that evaluation and discussion of such issues should be included as part of the analysis of transmission needs in RPS plans. See "Development Plan for the Phased Expansion of Transmission in the Tehachapi Wind Resource Area: Report of the Tehachapi Collaborative Study Group" (March 16, 2005).[10] This report points to the need for utilities to include some understanding of renewable resources groupings, possible economies of scale for transmission from areas with potentially concentrated resources, and network benefits and costs of concentrated renewable resources, as well as alternatives to building new transmission to access renewable resources.

When we recently initiated I.05-09-005, we made the many issues involved in transmission planning and construction for renewable resources the focus of that proceeding. We intend to coordinate this proceeding and that one closely. The existence of I.05-09-005 does not, however, relieve the utilities of the responsibility of analyzing transmission issues and identifying appropriate steps to deal with them in both their short-term and long-term RPS procurement plans.

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[10] This report is available at http://www.cpuc.ca.gov/PUBLISHED/REPORT/48819.PDF.

In D.05-07-039, we required that utilities allow delivery points outside their service territories and bids having curtailability as an attribute, as immediate steps that could reduce the impact of transmission constraints on RPS procurement. The utilities' current long-term plans do not include these elements. We will require that analysis of the impact of delivery points, curtailability, remarketing costs and benefits, and other delivery-related issues be included in future long-term plans, in the transmission planning component. PG&E and SCE are free to include a preliminary analysis in their supplemental plans under this order, but are not required to do so. SDG&E should, however, incorporate this preliminary analysis in its current supplement, since it has identified transmission as its primary constraint in attaining the 2010 target.

3. Contingency Planning

None of the utilities has included any alternative or contingency planning. SDG&E simply says that it has no contingency plan, even though it believes that its non-contingency planning for RPS compliance will fail if new transmission is not available by 2010. SCE has made planning estimates for base case, high need case, and low need case, which is a good start, but has not analyzed the contingencies that might impede attaining RPS targets or identified steps it might take to overcome such impediments. PG&E does not discuss contingency planning at all.

We do not expect extraordinarily detailed contingency planning, but we agree with ORA that prudent planning includes reasonable analysis of the possibility that not all of the assumptions and actions outlined in the main plan will hold true or occur in the timeframe assigned to them. This is especially critical with respect to transmission, since failure or extended delay of planned transmission could have a large impact on RPS procurement. ORA and UCS note that both PG&E and SDG&E include assumptions or proposals that are not now part of the RPS program (*e.g.*, out-of-state delivery of electricity, RECs that are tradable in a market). The utilities' contingency planning should also assume that current conditions of the RPS program will continue, unless there is a clearly articulated basis for assuming that certain changes will occur in a particular time frame.

4. Procurement Strategies

All the issues discussed above suggest that, as ORA, TURN and UCS urge, it is not wise for the utilities to set as their target 20.0% of their retail sales to be procured from eligible renewable resources in 2010. The 2010 target date is fast approaching. The utilities' planning ought to include procuring more than the exact amount of their projected incremental procurement target (IPT) each year. TURN points out that not all contracts come to fruition. SCE notes that some attrition in its baseline resources is expected.

Many elements must be in place for planned resource development to turn into delivered energy. Since the utilities are subject to being penalized if they fail to meet RPS goals,[11] they should employ some margin of safety to guard against reasonably likely problems, such as errors in projections, big changes in load that could not be forecast, and delays in upgrading transmission. We therefore will require the utilities in their supplements to make an initial quantification of their "margin of safety" in RPS procurement, both in terms of their annual procurement targets and in relation to the 2010 target date. We recognize that these efforts will necessarily be preliminary, but it is nonetheless important for

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[11] D.03-06-071, *mimeo.*, pp. 52-53; D.03-12-065, *mimeo.*, pp. 8-20.

the utilities to begin to develop such margins of safety. We intend to require such quantification, with supporting analysis, in both annual RPS plans and long-term RPS planning components in the future.

We note finally that Energy Action Plan II expresses our intention to press forward toward Governor Schwarzenegger's goal of having 33% of California's electricity generated from renewable resources by 2020. Thus, the full value of any procurement of renewables that is planned as greater than 1% annually or 20% by 2010 will be captured either to make up for unexpected shortfalls in other renewables deliveries, or to make progress toward the state's next goal for renewable energy.

C. Individual Utility Plans

1. PG&E

Commenters have raised questions about PG&E's analysis of renewable resources and its approach to repowering. Both areas should receive more attention than PG&E's current plan provides.

Overall, PG&E relies on the Energy Commission's estimate of possible renewable resources in its service territory. PG&E then concludes, without any further analysis, that it should have no problems meeting its RPS goals without major transmission upgrades and without aggressive repowering efforts. As CEERT points out, however, relying on a study of theoretically available renewable resources is not the same as planning for attainment of the 20% RPS goal by 2010. PG&E does not identify any resources or class of resources, or any amount of resources, that it believes will be available in a particular time frame. PG&E will certainly find out what is available in its RPS solicitations, but its current plan will not help it determine if any transmission changes *could* be needed, or if remarketing agreements with other utilities would be beneficial, or if the utility should set a particular goal for repowered wind contracts.

This relatively passive approach carries over to PG&E's discussion of its resource planning preferences. Its resource "stack" has biomass and biodiesel as its first two choices. Yet PG&E also notes that these resources are likely to be too expensive. This calls into question the value of the preference ranking, since the meaning of a preference for a resource that cannot economically be deployed is unclear.

The high ranking given to biofuels pushes wind repowering down to third on PG&E's list, although PG&E concedes that repowering would be efficient and effective. The Altamont Pass Wind Resource Area (Altamont Pass) is in PG&E's service territory. It is currently providing electricity to PG&E's customers and is well-understood. Here, the ranking is more than merely illustrative. For resources that bid into an RPS solicitation, a utility's low planning ranking of a particular resource would not be allowed to interfere with the least cost/best fit analysis of the bid. But repowering contracts may be bilaterally negotiated rather than bid into a solicitation, as PG&E notes in its plan.[12] If the utility's internal planning downgrades repowering, it could have a negative impact on the utility's pursuit of repowering opportunities.

Several commenters note issues that may hamper the bilateral negotiation of repowered wind contracts. While we continue to encourage the utilities to seek repowered wind contracts through bilateral negotiation, we also urge them

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12 We will allow bilateral repowering contracts that do not use PGC funds to be presented by advice letter, as contracts from RPS solicitations are. See D.03-06-071, *mimeo.*, pp. 40, 59.

to seek repowered wind projects through RPS solicitations, where the repowers would be evaluated on least cost/best fit criteria and would, if relevant, be eligible to apply for SEPs.

CalWEA urges that SCE's repowering principles be imposed on PG&E.[13] We decline to do that, since the situations of PG&E and SCE with respect to wind repowering are not identical. We will, however, require PG&E to develop an analogous set of principles, focused on wind repowering at Altamont Pass (though not excluding other facilities). PG&E should include those principles in its supplement, as part of a conceptual plan, including a timeline, for acquiring repowered wind resources. We expect that PG&E will accord repowering a high priority, which would be reflected in actual contracts submitted for approval well before 2010.

CalWEA makes a number of suggestions for further Commission requirements for repowering projects.[14] As we did in D.05-07-039, we prefer to rely on the business judgment of the parties with respect to contracting issues beyond those addressed in D.04-06-014.[15] Although we share CalWEA's concern that PG&E and SCE have not yet taken full advantage of the opportunities

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[13] CEERT and UCS also find PG&E's repowering plan inadequate compared to that of SCE.

[14] These include requiring the development and use of form repowering contracts; ordering that repowers without increases in capacity may rely on existing interconnection agreements; requiring a minimum contract length of 10 years; and requiring the utilities to respond to repowering proposals within 30 days.

[15] Also as we did in D.05-07-039, we encourage the parties to inform us of any specific contracting issues that appear to be creating impediments to the attainment of RPS goals.

provided by repowering, we are not persuaded that imposing CalWEA's detailed requirements at this time will induce them to do so. We continue to believe that repowering existing wind facilities is an important resource for the RPS program and are concerned that more progress has not been made to date. As we stated in D.03-06-071, ". . . the repowering of existing wind facilities in prime locations is a common-sense approach to increasing procurement of renewable energy, with costs that should be lower than for new greenfield projects." (*Mimeo.*, p. 58.) But it is also important that we not, by too-detailed prescription, create a special status for repowering, which is one of an array of renewable resource options. The utilities have annual procurement targets to meet in an aggressive time frame; this should be incentive enough to make appropriate bilateral repowering deals and encourage repowered wind projects to bid in RPS solicitations.

The Center for Biological Diversity (CBD) is highly critical of the management of Altamont Pass wind turbines, citing a study by the Energy Commission on the high number of bird deaths associated with the facilities. (Developing Methods to Reduce Bird Mortality In the Altamont Pass Wind Resource Area, August 2004.[16] CBD urges that PG&E be required to include in any repowering contracts a set of conditions that would be more protective of birds than the current operations at Altamont Pass. We decline to require PG&E to include these conditions. As CBD acknowledges, the Alameda County Board of Supervisors, not this Commission, is the permitting agency for the Altamont Pass wind facilities. We will not require specific contract provisions for

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[16] This study is available at http://www.energy.ca.gov/pier/final_project_reports/500-04-052.html.

repowering projects at Altamont Pass, since we do not want to create inconsistencies with permit conditions recently set by Alameda County. PG&E remains able to negotiate terms with Altamont Pass projects that are consistent with permitting and RPS requirements.

PG&E has not presented any transmission analysis. It is not enough to say "we don't anticipate any need for transmission; " some analysis of why not is needed. As an example, the Tehachapi Study Group report includes the possibility of transmission from the Tehachapi region to PG&E, as well as to SCE. PG&E may decide not to pursue such ideas, but in submitting an RPS plan that goes out to 2014, it must include some discussion of a range of possibilities – including transmission from the Tehachapi region -- even if it discounts some of them. It must articulate analysis of the value, probability of occurring, and rough costs and benefits of a variety of transmission options. Otherwise, it is not planning, but merely projecting the status quo into the future.

No contingency planning appears in PG&E's plan, perhaps because of PG&E's reliance on the Energy Commission's estimates of potential resources. Some effort, however, needs to be made to anticipate potential issues and problems that could impede PG&E's RPS compliance.

In its supplement, PG&E should include more specific discussion of available resources; a conceptual plan, including principles for repowering and a timeline, for pursuing repowered wind contracts; a discussion of what transmission may or may not be needed, with reasons, to attain the RPS goals in 2010; and an analysis and plan for contingencies that may impede attainment of RPS goals.

2. SCE

Commenters are generally supportive of SCE's long-term planning, and SCE indeed presents useful planning information. We note particularly the analysis underlying SCE's high/low/base case presentation. SCE's principles for repowering also are clear and provide useful guidance to the utility in that area. CEERT and IEP criticize SCE's inclusion of a potential large solar thermal project without analysis of its characteristics, likelihood of successful transition from experimental to commercial application, and lack of competitive bidding. SCE has since filed an advice letter seeking approval of a contract for the project. (AL 1909-E.) Without in any way prejudging the outcome of the review process for this contract, we note our agreement with the commenters that, in general, planning that relies on experimental technologies or other elements that have not yet been adapted for the use the utility intends, should include some analysis of the likelihood of success, and include contingency planning in case of total or partial failure of the project, delay in implementation, funding problems, and other typical problems of new projects.[17]

SCE's transmission plan presents a comprehensive list of possible transmission upgrades that would be relevant to RPS procurement. SCE does not, however, analyze which possibilities would be necessary for its compliance, nor analyze the possibilities that some or all of the listed transmission projects would not be built, or would not be available by 2010. The plan therefore does not provide assistance in identifying those transmission construction delays or

[17] SCE includes planning scenarios with and without the proposed project, but does not undertake analysis of the likelihood of the project's implementation at the planned-for level.

deficiencies that would impede attainment of the 20% goal by 2010, and for which some alternate or contingency planning would be useful.

3. SDG&E

SDG&E estimates that 75% of the energy it will use to meet its RPS goals in 2010 will come from outside its service territory. It also notes that, without at least one new 500 kV transmission line coming into its territory from the east, it will not be able to bring into its service territory the volume of power needed for its compliance planning. SDG&E does not, however, present a transmission plan or a timeline for developing a proposal for new transmission. This large omission makes it difficult to evaluate SDG&E's planning, as ORA observes.

SDG&E also suggests that a market mechanism for trading RECs that can be used for RPS compliance will be needed in order for it to attain the 2010 goal. SDG&E does not however, estimate what percentage of its goal would require the use of tradable RECs, or how soon such RECs would be needed.

Since SDG&E states that its ability to attain the 2010 target requires on the existence of two circumstances that do not presently exist (the new 500 kV line and tradable RECs), it ought to have a contingency plan. In its supplement, SDG&E must include careful analysis of its situation if a program for tradable RECs does not exist, and/or if a new 500 kV transmission line is not operational by 2010. SDG&E should also include a transmission plan that addresses a range of issues related to transmission, including planning for a new transmission line, a timeline for permitting proceedings for a new transmission line, the impact of delay in building a new transmission line, delivery outside SDG&E's service territory, bids having curtailability as an attribute, remarketing, and other relevant steps to address transmission constraints.

D. Next Steps

To complete the long-term RPS planning from 2004 that we referred to this proceeding in D.04-12-048, the utilities must file and serve supplements to their long-term plans within 60 days of the date of this decision. The supplements for all utilities must analyze contingencies that might impede the planned procurement activities and/or delay attainment of the goal of 20% of electricity from renewable sources by 2010. Plans for dealing with those contingencies must also be set out, including an initial quantification of a margin of safety in procurement. PG&E and SDG&E must also include more specific transmission planning. PG&E must further provide a more complete conceptual plan for pursuing repowering at Altamont Pass wind facilities.

The supplements will conclude the 2004 long-term RPS planning process, but we expect that they will also inform the 2006 planning process. We anticipate that the assigned Commissioner and assigned administrative law judge will set a schedule for 2006 RPS draft procurement plans and requests for offers that will require submission in this proceeding late in 2005 or early in 2006. The 2006 long-term planning cycle in D.04-04-003 or a successor proceeding will begin early in 2006. In both forums, information and analysis developed in the supplements will be useful.

We now direct the utilities, as contemplated by § 399.14(a), to continue their long-term RPS planning by including robust RPS segments in their long-term procurement plans, to be filed in R.04-04-003 or its successor proceedings. As we noted in D.05-07-039, annual RPS plans and RFOs for solicitations will continue to be addressed in this proceeding or its successor proceedings.

IV. Assignment of Proceeding

Michael R. Peevey is the Assigned Commissioner and Peter V. Allen and Anne E. Simon are the assigned Administrative Law Judges (ALJs) for this proceeding.

V. Comments on Draft Decision

The draft decision of ALJ Simon in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(g)(1) and Rule 77.7 of the Rules of Practice and Procedure. Comments were filed on September 26, 2005 by CBD, Green Power, ORA, PG&E, SDG&E, SCE, and UCS. Reply comments were filed on October 3, 2005 by CalWEA, SCE, and UCS.

CBD provides a useful summary of the action taken by the Alameda County Board of Supervisors with respect to renewal of the permits of Altamont Pass wind facilities. CBD notes that the permit conditions require only about 40 MW of repowering by 2010, in contrast to PG&E's illustrative planning estimate that it will acquire approximately 400 MW of new and repowered wind by 2010. CBD urges us to develop a special cost mechanism to support such contracts.

We agree with CBD that PG&E cannot expect the conditions in the Alameda County permit renewals to provide the repowered wind resources it needs. We revise the draft decision to strengthen our direction to PG&E on Altamont Pass resources. We will not undertake here any special treatment for Altamont Pass wind resources, since the Legislature has provided the MPR/SEP framework for the costs of RPS procurement. We revise the draft decision to encourage the submission of bids for wind repowering in RPS solicitations where, if the bid meet the least cost/best fit evaluation criteria, a winning bid would be eligible to apply to the Energy Commission for SEPs.

Green Power points out that the utilities must be more aggressive in responding to possible shortfalls in RPS procurement. It notes that many existing contracts will be expiring in 2006, raising the possibility that the utilities' baseline resources may erode. Green Power also notes that many contracts with QFs did not come to fruition, suggesting that a similar problem may occur with RPS contracts.[18] Because contracting with a project using a technology that is not commercially tested also has risks of non-completion of the planned project, Green Power recommends applying a discount to the planned capacity estimates of such projects for planning purposes. We agree that the utilities should develop a robust analysis of possible sources of shortfalls in procurement and should take steps to prevent shortfalls due to contract failure. We revise the draft to make this requirement more explicit.[19]

ORA generally supports the draft decision and emphasizes the importance of contingency planning for the utilities.

PG&E raises several concerns about the draft decision's requirements and timetable for submission of supplements to the utilities' plans, as well as about the coordination of transmission planning processes. PG&E states (as does SCE) that the draft decision's expectation that the supplements will be fully public is not realistic. Much of the information that forms the basis of its planning, PG&E asserts, is confidential material related to its RPS solicitations. We understand

[18] In its initial comments, TURN also suggested, based on its RPS experience, that some proportion of contracts would not result in energy deliveries.

[19] Green Power also suggests that the utilities use standardized categories for resource types. We will explore this suggestion in the context of the 2006 RPS procurement plans.

this concern, but seek to maximize the quality and quantity of planning analysis that is publicly available. We revise the text of the draft decision to describe our expectations more fully. PG&E also believes that 60 days, rather than 30, is appropriate for submission of the supplements. We agree, and both change the time period and expand on the relationship of the supplements to other submissions.

PG&E asserts that the draft decision misconstrues the transmission component of its plan by failing to acknowledge PG&E's incorporation of its transmission cost ranking report. The TRCR, however, is an aid in annual procurement, not a long-term transmission planning process. PG&E also points out that transmission planning for renewables is a complex process, and filings in this proceeding will be related to those in other proceedings. PG&E suggests that we centralize renewables transmission issues in I.05-09-005, which we initiated last month. Although we intend to coordinate these two proceedings closely, and revise the text of the draft decision to reflect this, we do not believe that RPS procurement planning should proceed without attention to transmission planning and related contingencies.

Finally, PG&E presents its view that repowering of wind facilities at Altamont Pass is a more complex process than the draft decision suggests. We welcome PG&E's statement that it will provide additional information in its supplement about the recent Alameda County permitting process for Altamont Pass facilities. We revise the text of the draft decision to reflect current information about the permitting process and to expand our discussion of repowering options.

SDG&E would like to delay filing its supplement until it has more information available, and suggests that the supplement should be filed either with its long-term plan in R.04-04-003 early in 2006, or by January 15, 2006. We do not adopt either suggestion, but do extend the period of time for preparing the supplement.

SCE, as did PG&E, asserts that the use of confidential information is essential to the planning we requested in the supplement. Like the other utilities, SCE also seeks to extend the period for filing the supplement, either to the 2006 RPS procurement plan or to a time 60 days after the mail date of this decision. We make changes to the draft decision responding to these concerns. SCE also claims that its efforts to engage its current wind resources in negotiations on repowering are not meeting with a great deal of success. We note this issue in the revised text of the draft decision.

UCS focuses its comments on contingency planning. It seeks, among other things, that we require the utilities to analyze transmission issues in the context of contingency planning and that we require plans to include an analysis of possible deviations from expected output. We find merit to some of these specific suggestions, but see the 2006 planning process as the more appropriate time to implement them. We clarify in the text our expectations for the relationship of the supplements to 2006 planning processes.

Findings of Fact

1. It is reasonable for utilities to make estimates of future procurement from specific types of renewable resources for planning purposes.

2. It is reasonable for utilities to plan for the possibility that not all planned renewable developments will deliver the planned-for energy, whether due to erosion of the baseline renewable resources, errors in load forecasting, transmission constraints, or unforeseen difficulties in project development.

3. It is reasonable for utilities to make estimates of future needs for transmission, delivery points, remarketing costs, and other delivery issues for renewable resources for planning purposes.

4. The planning estimates of the utilities for the year 2010 currently identify wind, geothermal, and solar thermal resources as significant sources of renewable energy procurement; these resources may be located in areas that are remote from the utility's load center.

5. The utilities' long-term RPS plans do not adequately address the consequences of the estimated reliance on resources that may be remote from the utilities' load center.

6. The long-term RPS plans of the utilities do not address all areas necessary for adequate RPS planning.

7. It is reasonable to require the utilities to supplement their plans, as needed, with respect to transmission planning, repowered wind resources, and alternative and contingency planning.

Conclusions of Law

1. Utilities should provide analysis and reasoned discussion in their RPS planning of the consequences of reliance for RPS procurement on resources remote from their load centers.

2. Utilities should address in their long-term RPS planning the availability of renewable resources both in and remote from their service territories.

3. Utilities should address in their long-term RPS planning transmission planning, including delivery outside the utility's service territory, curtailablity, remarketing costs and benefits, and other alternatives to building new transmission.

4. Utilities should address in their long-term RPS planning the repowering of wind facilities currently under contract to the utility.

5. Utilities should include in their long-term RPS planning analysis that includes high, low, and base case scenarios.

6. Utilities should address in their long-term RPS planning potentially significant impediments to RPS compliance and include contingency planning addressing the identified impediments.

7. Utilities should explicitly address in their long-term RPS planning lessons learned from previous planning cycles.

8. In order to guard against shortfalls of planned renewable energy deliveries, utilities should provide in their RPS planning for procurement greater than the annual IPT required to reach the goal that 20% of their retail sales of energy be from eligible renewable resources by 2010.

9. Beginning in 2006, utilities' long-term planning for RPS compliance should be integrated with their general long-term procurement planning, in R.04-04-003 or its successor proceedings.

10. In integrating RPS planning with general procurement planning, utilities should specifically identify RPS planning components.

11. In order to begin more complete RPS planning, the utilities should, within 60 days of the mail date of this decision, supplement their current filings as follows:

a. PG&E must include:

(1) Basic analysis of the likelihood of development of its preferred renewable resources by 2010;
(2) Basic analysis of possible needs for transmission upgrades by 2010;
(3) A conceptual plan, including repowering principles and a timeline, for pursuing repowering opportunities for wind resources in the Altamont Pass Wind Resource Area;

(4) An initial quantification of "overprocurement" to create a margin of safety for RPS procurement; and
(5) Contingency planning that addresses the most significant potential impediments to compliance with the 20% by 2010 goal.

b. SCE must include:

(1) Analysis of possible needs for transmission upgrades, with reference to those that are most needed for compliance with the 20% by 2010 goal;
(2) An initial quantification of "overprocurement" to create a margin of safety for RPS procurement; and
(3) Contingency planning that addresses the most significant potential impediments to compliance with the 20% by 2010 goal.

c. SDG&E must include:

(1) Analysis and discussion, including a timeline for a CPCN submission, of possible transmission upgrades to be operating by 2010;
(2) Analysis of the impact of delivery points outside its service territory, bids having curtailability as an attribute, and remarketing arrangements on its ability to attain the 20% by 2010 goal;
(3) An initial quantification of "overprocurement" to create a margin of safety for RPS procurement; and
(4) Contingency planning that addresses the most significant potential impediments to compliance with the 20% by 2010 goal, including transmission constraints and the absence of a market mechanism for using tradable RECs for RPS compliance.

12. In order for RPS planning to move forward expeditiously, this decision should be effective today.

INTERIM ORDER

IT IS ORDERED that:

1. Not later than 60 days from the mailing date of this decision, Pacific Gas & Electric Company (PG&E) must serve and file a supplement to its long-term

procurement plan for the Renewables Portfolio Standard (RPS) program, including at least the following elements:

(a) Basic analysis of the likelihood of development of its preferred renewable resources by 2010;
(b) Basic analysis of possible needs for transmission upgrades by 2010;
(c) A conceptual plan, including repowering principles and a timeline, for pursuing repowering opportunities for wind resources in the Altamont Pass Wind Resource Area;
(d) An initial quantification of "overprocurement" to create a margin of safety for RPS procurement; and
(e) Contingency planning that addresses the most significant potential impediments to compliance with the RPS goal of 20% of retail sales generated by eligible renewable resources by 2010.

2. Not later than 60 days from the mailing date of this decision, Southern California Edison Company (SCE) must serve and file a supplement to its long-term RPS procurement, including at least the following elements:

(a) Analysis of possible needs for transmission upgrades, with reference to those that are most needed for compliance with the 20% by 2010 goal;
(b) An initial quantification of "overprocurement" to create a margin of safety for RPS procurement; and
(c) Contingency planning that addresses the most significant potential impediments to compliance with the RPS goal of 20% of retail sales generated by eligible renewable resources by 2010.

3. Not later than 60 days from the mailing date of this decision, San Diego Gas & Electric Company (SDG&E) must serve and file a supplement to its long-term RPS procurement, including at least the following elements:

(a) Analysis and discussion, including a timeline for a CPCN submission, of possible transmission upgrades to be operating by 2010;
(b) Analysis of the impact of delivery points outside its service territory, bids having curtailability as an attribute, and remarketing arrangements on its ability to attain the 20% by 2010 goal;
(c) An initial quantification of "overprocurement" to create a margin of safety for RPS procurement; and

(d) Contingency planning that addresses the most significant potential impediments to compliance with the RPS goal of 20% of retail sales generated by eligible renewable resources by 2010, including at least transmission constraints and the absence of a market mechanism for using tradable RECs for RPS compliance.

4. The utilities' future long-term planning for RPS compliance shall be conducted as part of general procurement planning in Rulemaking 04-04-003 or its successor proceedings.

5. The utilities' future long-term plans for RPS compliance shall include specific and identifiable RPS planning components in general procurement planning documents, and shall address at least the following topics:

- available renewable resources;
- transmission planning (including planning for delivery points outside the utility's service area, for curtailability of delivery, remarketing, and other alternatives to construction of new transmission upgrades);
- high, low, and base case scenarios, with analytic support for each;
- repowering of wind facilities currently under contract to the utility;
- any need to guard against shortfalls of planned deliveries by procurement greater than the annual incremental procurement target required to reach the goal that 20% of their retail sales of energy be from eligible renewable resources by 2010; and
- identification of potentially significant impediments to RPS compliance; and contingency planning addressing the identified impediments.

This order is effective today.

Dated October 6, 2005, at Los Angeles, California.

MICHAEL R. PEEVEY
President
GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

Commissioner Dian Grueneich recused herself
from this agenda item and was not part
of the quorum in its consideration.

Commissioner John A. Bohn, being necessarily
absent, did not participate.